BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020 (Filed September 28, 2017)

COMMENTS OF THE INDEPENDENT ENERGY PRODUCERS ASSOCIATION ON PARTIES' TRACK 2 TESTIMONY AND THE JULY 19, 2018 RESOURCE ADEQUACY WORKSHOP

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As authorized by the email ruling of Administrative Law Judge Peter Allen issued August 1, 2018, the Independent Energy Producers Association (IEP) provides comments on Track 2 testimony and the Resource Adequacy (RA) workshop convened on July 19, 2018.

I. OVERVIEW

In their testimonies, many parties recognize the unique circumstances that characterize the California energy markets today and the associated market volatility and uncertainty that those circumstances create. Uncertainties exist regarding the amount of capacity needed by location and year as the state transitions to a low-carbon future by 2025-2030. Uncertainties exist regarding the scope, scale, and pace of the retirement of existing capacity resources and migration of load among load-serving entities (LSEs), and the extent to which new and emerging technologies are capable of meeting near-term and long-term capacity requirements. Finally, uncertainties exist about which entity or entities will be procuring needed capacity.

Give these market uncertainties, some parties conclude it would be more prudent for the Commission to shorten the duration of its adopted multi-year RA framework and reduce the forward annual obligations.

IEP draws the exact opposite conclusion. The Commission should employ a multi-year framework of relatively long duration (i.e., five years) with relatively high forward obligations (i.e., no less than 80% for the last year of the forward procurement obligation) precisely because of the significant risks and uncertainties that will pervade California's energy sector over at least the next 2 to 7 years as resources change, load shifts, and the date for achievement of greenhouse gas emission-reduction goals approaches.

Procedurally, the issues before the Commission related to the duration of the forward RA capacity procurement obligation and the amount of the annual obligation for each forward year are independent from consideration of more complex issues such as who has the RA procurement obligation (e.g., LSEs, a Central Buyer, a centrally administered capacity market, or some combination). The Commission need not and should not defer decisions regarding duration and amount of the obligation until the more complex issues are resolved. The Track 2 decision scheduled for late 2018 is the appropriate means for the Commission to send clear signals regarding the amount of capacity to be procured and the duration of the obligation. Policymakers, customers, and suppliers will benefit immensely from clear market signals on these matters.

Below, IEP addresses in greater detail parties' proposals and comments related to the duration of a multi-year RA framework, the amount of the obligation as a percent for forecast RA capacity need, the scope of RA products that ought to be integrated into a multi-year RA framework, and other matters relevant to this discussion. IEP also provides recommendations regarding the procedural schedule and the need for additional workshops or hearings.

II. CURRENT PRACTICES IN FORWARD RA CAPACITY PROCUREMENT

LSEs collectively procured approximately 76% of the System RA capacity forecast to be needed in 2018 (i.e., one-year forward). This procurement occurred at a time when the one-year forward System RA requirement was 90% of the forecast system RA need. LSEs collectively *voluntarily* procured 63% of the Year 3 need (2020) and 57% of the Year 5 need (2022).[1]

In addition, LSEs collectively procure 80% or less of local RA capacity forecast needed in many local areas five years forward. The bulk of the forward procurement that occurs is a product of utility procurement (i.e., utility-owned capacity or centralized procurement such as the Cost Allocation Mechanism (CAM)). Forward procurement typically is not a product of forward procurement by electric service providers (ESPs) or Community Choice Aggregators (CCA).[2]

LSE procurement overall is low and trends downward in coming years. While contracted local RA capacity procurement exceeds the local requirements one-year forward in 70% of the local areas, individual local areas (e.g., Sierra) exhibit persistently low levels of procurement one-year forward, i.e., procurement of no more than 71% of next year's forecast need. On a 3-year forward basis, local RA capacity procurement in 40% of the local areas falls below 85% of the forecast need. On a 5-year forward basis, local RA capacity procurement in 70% of the local areas falls below 75% in the forecast capacity need, and local RA capacity procurement in 50% of the local areas falls below 66% of forecast need.[3]

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[1] Energy Division Staff Proposals: Multi-year RA Requirements, Figures 1-3, pp. 5-8.
[2] Energy Division Staff Proposals: Multi-year RA Requirements, Figures 4-5, p. 8.
[3] Energy Division Staff Proposals: Multi-year RA Requirements, Table 1, p. 11.

The Alliance for Retail Markets (AReM) in its testimony also presented data regarding RA capacity procurement on a three-year forward basis.[4] The AReM testimony indicates that procurement on a two-year forward basis (for 2019) and a three-year forward basis (for 2020) totals only 81% and 74% of the forecast need for those forward years. Equally important, these data reveal that approximately all the 2- and 3-year forward procurement (approximately 99%) was conducted by the investor-owned utilities (IOUs).[5]

These data suggest that relying on a voluntary framework to ensure the availability of needed capacity resources over the near term, as is the case today, is likely to prove insufficient to ensure the availability of needed capacity. Moreover, the data suggest that multi-year procurement of needed capacity over the past five years has been highly dependent on the voluntary actions of the IOUs. Non-IOU LSEs (ESPs and CCAs) typically have not voluntarily entered into long-term RA capacity contracts. The current procurement pattern is troubling, because the risk of load departure from IOU bundled service is now at record levels and is expected by many to increase.

III. DURATION OF THE MULTI-YEAR RA PROCUREMENT OBLIGATION

Overall, the existing Commission-adopted multi-year RA framework of two years for local RA capacity will prove insufficient to mitigate the risk of out-of-market backstop procurement to ensure sufficient capacity is available when and where needed over the next 3 to 7 years. The current approach is likely to perpetuate the pattern of increasing the amount of out-of-market backstop procurement. While some argue that volatility is a reason LSEs should not be required to procure RA capacity forward, i.e., because they are uncertain about what their

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[4] The AReM testimony is derived from data reported by the Energy Division in April 2017.
[5] Track 2 Testimony on Behalf of the Alliance for Retail Energy Markets, Table 1, p. 9.

needs may be, the market uncertainty is precisely why the Commission should extend its RA requirements out to five years.

The data suggest that a multi-year requirement of sufficient duration with relatively high annual obligations is needed to provide greater transparency on forward contracting of needed RA capacity. Moreover, a five-year duration at a relatively high annual obligation is necessary to maintain the historical pattern of RA capacity procurement undertaken primarily by the IOUs.

Accordingly, IEP supports generally the Energy Division's proposal for a five-year forward RA procurement obligation with modifications related to the amount of the obligation. Moreover, as discussed in greater detail below, the five-year framework proposed by the Energy Division for local RA capacity should be expanded to include all RA products, i.e., system, and flexible RA capacity, because of the unique market conditions and uncertainties expected to persist into the near future.

IV. AMOUNT OF ANNUAL OBLIGATION

The Energy Division Staff Proposal generally reduces the year-to-year procurement obligation by 5% per annum. However, the proposal deviates from this general pattern and proposes to lower the forward obligation by 10% between Year 3 and Year 4. The deviation from the general pattern of a 5% per annum reduction between Year 3 and Year 4 is unexplained. The effect of applying a 10% reduction between Year 3 and Year 4 is to lower the Year 5 obligation to only 75% of the forecast need.6

While IEP generally supports the approach proposed by the Energy Division, we see no rationale for deviating from a framework in which the forward obligation declines on a straight-line, 5% each year across the entire five-year duration. If the anomalous 10% decline between

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[6] Energy Division Staff Proposal: Multi-year RA Requirements, p. 13.

Year 3 and Year 4 were replaced by a 5% decline, then the Energy Division Staff Proposal would impose an 80% obligation in the fifth year. IEP supports this approach.[7]

A 5% per annum reduction is consistent with the Track 1 decision adopting a multi-year local RA requirement. In addition, evidence presented in Track 1 indicates that CCAs anticipate a risk of load departure of about 2% to 2.5%. When summed over the five-year duration, the reductions of the forward RA capacity obligation by 5% per annum create a 20% hedge against the risk of forecasting error and load departure. Moreover, setting an 80% forward procurement obligation in Year 5 reasonably replicates the rate of voluntary forward procurement reported in the Energy Division Staff Proposal, although the obligation would be shared among all jurisdictional LSEs.

A. <u>Uncertainty and Variability in RA Capacity Need Supports Setting Relatively High Annual Obligations Over the Entire Multi-year Duration</u>

The Energy Division Staff Proposal presented data related to one-year forward local capacity requirements by year covering 2012-2019. The data are disaggregated by the 10 local areas, and then summed.[8]

Based on Energy Division data, Table 1 below presents the net change in local capacity requirements (LCRs) by 10 local areas comparing the 2012 LCR and the 2019 LCR.

[7] The IEP Multi-year RA Proposal set a five-year duration, and an 80% obligation in Year 5.
[8] Energy Division Staff Proposal: Multi-year RA Requirements, Table 7, p. 22.

Table 1:

Net Change in Local Capacity Requirements 2012-2019

	2012 Local Capacity Requirement (MW) (A)	2019 Local Capacity Requirement (MW) (B)	Net Change[9] B/A
Humboldt	212	165	**78%**
North Coast/North Bay	613	689	**112%**
Sierra	1974	2247	**114%**
Stockton	567	777	**137%**
Bay Area	4278	4461	**104%**
Fresno	1907	1671	**88%**
Kern	325	478	**147%**
LA Basin	10865	8116	**75%**
Big Creek-Ventura	3093	2614	**85%**
San Diego-Imperial Valley	2944	4026	**137%**
TOTAL	26778	25244	**94%**

The Energy Division Staff Proposal also presented data related to the five-year *forecast* of LCRs covering the years 2017-2023.[10] Here again, based on Energy Division data, Table 2 below presents the net change in LCRs forecast to be needed year-to-year between 2017 and 2023.

[9] The Net Change in local capacity requirements for each of the local areas over the eight-year historical period is derived by dividing the 2019 LCR by the 2012 LCR (based on the data presented in Energy Division's Table 7).
[10] Energy Division Staff Proposal: Multi-year RA Requirements, Table 8, p. 23.

Table 2:

Net Change in Local Capacity Requirements 2017-2023

	2017 Local Capacity Requirement (MW) (A)	2023 Local Capacity Requirement (MW) (B)	Net Change[11] B/A
Humboldt	165	169	**102%**
North Coast/North Bay	446	553	**124%**
Sierra	1969	1924	**98%**
Stockton	440	439	**100%**
Bay Area	4281	4752	**111%**
Fresno	2110	1688	**80%**
Kern	434	182	**42%**
LA Basin	10019	6793	**68%**
Big Creek-Ventura	2537	2792	**110%**
San Diego-Imperial Valley	3156	4132	**131%**
TOTAL	25557	23424	**92%**

These data indicate several trends with regards to local capacity. First, while the statewide need for local capacity declined slightly (6%) between 2012 and 2019, the majority of the local areas (60%) experienced an increase in LCR by up to 31%. Similarly, while statewide need is forecasted to decline slightly (8%) between 2017 and 2023, the majority of the local areas (60%) are expected to experience an increase in LCR by as much as 31% between 2017 and 2023. Second, the biggest drop in forecast local capacity needs is in LA Basin local area, but the LA Basin also is the area in which the greatest market volatility is present due to resource retirements (e.g., of once-through-cooling units) and CCA formation. This suggests that a robust forward procurement framework of five years is necessary to ensure grid stability while these changes unfold over the next 3 to 7 years.

[11] The Net Change in forecast RA by local area for the period 2017-2023 was derived by dividing the forecast 2023 LCR by the 2017 LCR (based on the data presented in Energy Division Table 8).

The Utility Reform Network (TURN) also presented testimony comparing Commission-adopted LCRs for 2018 and 2019, and TURN compared these requirements against forecasts of LCRs made by the California Independent System Operator (CAISO) five years earlier, in 2013 and 2014. In addition, TURN converted the MW variance into a percentage variance. Overall, when assessing the absolute value of the MW deviation across all the local areas, the deviation from forecast totaled 1,176 MW (2018) and 2,068 MW (2019).[12] (IEP notes that individual variations within local areas between CAISO forecasts and adopted year-ahead requirements typically fall within the range of hundreds of MW but can range up to 1,100 MW (e.g., Sierra).) TURN concluded that the first two CAISO five-year forward local need forecasts significantly underestimated future LCRs in the Pacific Gas and Electric Company (PG&E) local areas and the San Diego-Imperial Valley local area, but significantly overestimated LCRs in the Southern California Edison Company (SCE) local areas.[13]

Capacity forecasting will never be precise. A certain amount of deviation should be expected. In response to these data, however, IEP draws several conclusions.

First, the accuracy of CAISO forecasts of LCRs made in 2013 and 2014 is not likely to be indicative of the accuracy of future CAISO forecasts of LCRs. The assumptions embedded in forecasting since 2010 have evolved due to changing policy initiatives (e.g., higher Renewables Portfolio Standard (RPS) goals, energy storage), changing resource plans (e.g., Integrated Resource Planning (IRP), RPS, distributed energy resources (DERs)), and experience gained

[12] For purposes of illustrating the magnitude of the deviation in forecasts year-to-year, IEP has focused on the absolute value. As noted by TURN, the deviation in 2018 of 1,176 MWs reflects an overall increase in the LCR compared to the forecast; while the deviation in 2019 of 2,068 MWs reflects an overall decrease in LCR as opposed to the forecast.
[13] Direct Testimony of Kevin Woodruff on Behalf of the Utility Reform Network, Table 5, p. 12.

through repeated modeling and forecasting. Future modeling assumptions used to forecast RA capacity requirements will improve with additional experience.

Second, the deviations between forecasts and "actuals" shown by TURN generally fall within the 20% bandwidth that would be in effect were the Commission to adopt an 80% forward procurement obligation of the forecast capacity need in Year 5, as proposed by IEP. Moreover, the percentage deviations associated with the larger local areas (Greater Bay Area, LA Basin, and San Diego/Imperial Valley) for 2019 are close to or well within the 20% bandwidth.

Third, while some of the local areas experience relatively large percentage deviations between the 2013/2014 forecast need and the 2018/2019 actual need, these deviations tend to be local areas in which the local RA requirements reflect relatively small amounts of MW. Relatively small changes in MW requirements (actuals) in the local areas can drive relatively high percentages changes even though the procurement impacts are relatively modest. For example, the deviation associated with the Kern local area in 2019 is a relatively modest 285 MW, yet this deviation in MW translates into a relative high percentage deviation (148%). Similarly, the relatively modest MW deviation of 2019 for the North Coast/North Bay local area is 173 MW, which translates into a percentage deviation of 34%.[14]

Fourth, the size of the variation *year-to-year* between the CAISO forecast and the Commission-adopted LCR is small considering the level of demand. For example, across all the years studied, the maximum year-to-year variance between the CAISO forecast and the adopted LCR in any single local area is 46 MW, while the maximum year-to-year reduction to the procurement requirement for any single local area totals 23 MW. Notably, both the maximum

[14] Direct Testimony of Kevin Woodruff on Behalf of the Utility Reform Network, Table 5, p. 12.

year-to-year increase and the maximum year-to-year decrease occur in the same local area, the San-Diego-Imperial Valley local area.[15]

B. Patterns in Voluntary Forward RA Capacity Procurement

Overall, the level of voluntary five-year forward procurement of local RA capacity in the North of Path 26 area was approximately 78% of the forecast need in 2022.[16] A similar pattern of forward procurement is present South of Path 26, where the level of forward procurement of local RA capacity was approximately 80% of the forecast need five-years forward, in 2022.[17]

While the aggregate data suggest that historical voluntary procurement of local capacity is around 80% of the forecast need five years forward, the aggregate data mask the important fact that the bulk of the procured local capacity is utility-owned capacity or centralized procurement conducted by the utilities (e.g., CAM procurement).[18]

Similar patterns of forward procurement apply to System RA capacity. For the five-year period covering 2018-2022, for example, the overall procurement of System RA capacity stands at 92% in Year 1 and declines to 58% in Year 4. The bulk of this forward System RA capacity procurement, e.g., 84% in 2018 and 97% in 2022, is attributable to IOU procurement directly or through centralized utility procurement such as CAM.[19]

IEP draws three primary conclusions from these data. First, the utilities have been the foremost procurers of local and system capacity on a forward basis over the past five years or so. Second, historical practices in which significant amount of local and system capacity were purchased on a forward basis (by the utilities) are unlikely to continue in an era when the risk of load migration is increasingly apparent. Third, absent a central procurement entity (CPE) or

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[15] Direct Testimony of Kevin Woodruff on Behalf of the Utility Reform Network, Table 3, p. 8.
[16] Energy Division Staff Proposal, Multi-year RA Requirements, p. 8, Figure 4.
[17] Energy Division Staff Proposal: Multi-year RA Requirements, p. 8, Figure 5.
[18] Energy Division Staff Proposal: Multi-year RA Requirements, p. 26, Tables A.4 and A.5.
[19] Energy Division Staff Proposal: Multi-year RA Requirements, p. 26, Table A.1.

centralized capacity market, it is imperative to set the local, system, and flexible RA capacity obligations ive years forward at no less than 80% of forecast need to hedge the high volatility in the energy markets and provide the Commission with sufficient information about who is doing what, where, and when from a capacity procurement perspective.

C. Setting an 80% Procurement Obligation in the Last Year

Many parties agree that the percentage obligation in the final year of the framework ought to be no less than 80%, even though parties may differ on the duration of the forward obligation. For example, the CAISO recommends setting the obligation at 100%, 100%, and 80% over 3 years;[20] San Diego Gas & Electric Company (SDG&E) sets the level at no less than 85% in the last year of a 5-year framework (assuming a Central Buyer) and no less than 80% in the last year of a 3-year framework (assuming no Central Buyer);[21] PG&E recommends, after an initial two year-transition period, a 100% obligation for local capacity on a five-year basis under a CPE model; AReM recommends no less than 80% in Year 3 of a 3-year local capacity obligation;[22] the Western Power Trading Forum (WPTF) recommends 100% in the last year of a 3-year forward framework;[23] and the California Community Choice Association (CalCCA) recommends no less than 80% in Year 3 of a 3-year framework[24].

In prior comments in this proceeding, IEP argued for forward obligations that are meaningful, that affect current behavior to ensure grid reliability during a period of heightened market uncertainty. We reiterate that recommendation. The data show that historically, RA capacity was procured at a level of about 80% of the forecast need. Yet the data also reveals that the utilities were the primary LSEs engaging in this type of forward procurement. Increased

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[20] CAISO Track 2 Testimony, Chapter 1, Table 1, p. 5.
[21] SDG&E's RA Track 2 Opening Testimony, Table 1, p. 25.
[22] AReM Track 2 Testimony, p. 1.
[23] Testimony of Gary Ackerman, p. 4.
[24] CalCCA Prepared Direct Testimony, p. 5.

levels of load departure and the risk of future load departure suggest that historical patterns of forward RA procurement have eroded, and the Commission should anticipate additional erosion in forward RA procurement unless specific obligations are set at relatively high levels of forecast need.

V. RA PRODUCTS SUBJECT TO THE MULTI-YEAR OBLIGATION

The CAISO recommends integrating local, system, and flexible capacity into the multi-year framework. The CAISO also notes that this approach provides significant benefits, including simplifying multi-year allocations, ensuring more optimal and effective resource procurement, and aiding in the more orderly retirement of non-essential gas-fired generation.[25] In addition, WPTF recommends full compliance of system, local, and flexible capacity over the timeframe of its proposed multi-year framework;[26] Middle River LLC notes that generators can offer a more efficient pricing structure when contracting is done on a longer-term forward basis across all RA products;[27] and NRG Energy endorses RA procurement (via a centralized clearinghouse) that includes system, flexible, and local/sub-local optimization.[28]

IEP agrees with the CAISO and these parties. RA products ought to be procured in an optimized manner to maximize efficiency and lower overall customer costs. Optimization is needlessly complicated if the products to be procured are subject to different durations or different percentage obligations, regardless of whether the procurement entity is an LSE, a central buyer, or a centralized capacity market.

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[25] CAISO Track 2 Testimony, p. 1.
[26] Testimony of Gary Ackerman, p. 4.
[27] Prepared Testimony of Joe Greco, p. 7.
[28] Prepared Testimony of Brian Theaker, pp. 9-10.

VI. RELATED ISSUES

A. Residual Procurement

Under the residual procurement model, the entity with the responsibility for residual procurement acts in a backstop role to procure resources needed to meet deficiencies in prior procurements. For example, the CAISO currently retains the responsibility in the existing RA framework to procure residual resources needed to maintain grid reliability not otherwise procured by LSEs.

CalCCA recommends that a CPE would procure residual Local RA capacity in each LCR. Under the CalCCA proposal, LSEs would rely on the CAISO as the Central Buyer for the residual Local RA capacity needs. Residual load would include procurement of Essential Reliability Resources (ERRs) plus 10% of the Net LCR for Year 1 and 5% of the Net LCR for Year 2 (net of the LCR apportioned to Publicly Owned Utilities).

As IEP understands the CalCCA model, rather than performing a pure residual procurement function to fill deficiencies in LSE RA capacity procurement, the Central Buyer (the CAISO) has a hybrid role. Specifically, the Central Buyer is obligated to procure a specified amount (10% or 5%) of local RA capacity. In addition, the Central Buyer is required to backstop deficiencies in LSE RA capacity obligations to the extent that deficiencies emerge. LSEs may at their volition procure more than their allocated local RA capacity share, but they have no requirement to do so. Moreover, the Central Buyer's residual role is limited to the procurement of local RA capacity, even though an LSE may have parallel obligations to procure system or flexible RA capacity.

The CalCCA model raises several questions. First, when does the Central Buyer enter the market to procure residual amounts? Does the Central Buyer wait until all LSE RA compliance showings have been submitted, in which case the role of the Central Buyer appears analogous to the role the CAISO performs today, except on a grander scale, since at least 10% of the need is set aside up-front for residual procurement. If the Central Buyer is required to await LSE RA compliance showings, will an LSE be incented to defer to the Central Buyer to buy all its RA resources in essentially a backstop mode, and how would that incentive affect procurement?

Second, assuming the Central Buyer is not prohibited from procuring needed RA resources at any time to meet its obligations (as defined), will the Central Buyer impact competitive markets and, if so, how?

Third, if the Central Buyer is limited to procuring local RA capacity only, what will be the impact of the Central Buyer's procurement practices for local RA when LSEs will still have system and flexible RA capacity procurement obligations? Where are the efficiency gains in a model that designates a Central Buyer as a residual procurement agent for an unspecified amount of RA capacity but no less than 10% in Year 1?

Fourth, under whose jurisdiction will the Central Buyer operate? If the Central Buyer competes to procure RA capacity in the marketplace, will the Central Buyer be a wholesale entity?

B. <u>July 19 Workshop</u>

The Energy Division convened a workshop on July 19, 2018, to discuss Track 2 issues. Specifically, the workshop was focused on three primary issues related to a multi-year framework: (a) duration, (b) amount of the obligation, and (c) central buyer. At times, the parties' discussion deviated from these matters to address other matters. Following up on the workshop, IEP offers comments on several topics raised at the workshop that relate to the IEP proposal for a multi-year RA framework of five years duration with a relatively higher annual percentage obligation set at no less than 80% of the forecast need.

1. RA and Transmission

Some parties recommended setting relatively low forward RA obligations to enable new transmission to emerge to relieve local constraints. IEP has concerns about this recommendation. First, in coordination with other energy entities in the state of California, the Commission's RA program is aligned with the California Energy Commission (CEC) Demand Forecast (including Updates), the CAISO's Transmission Planning Process (TPP), and the Commission's RPS/IRP/RA processes. Because RA is uniquely focused on ensuring grid reliability with available resources, speculative projects should not be allowed to count against an LSE's RA obligations. Only operating resources should count against an LSE's (or CPE's) forward obligation.

New or upgraded transmission projects approved in the CAISO TPP process can have the effect of lowering RA requirements depending on whether they are built. In this context, the RA value of a project approved in the TPP is like any other resource: it needs to be available and operational to provide RA services. Transmission projects (like other resource projects) can be cancelled or delayed due to changing economics, changing demand, and other factors. Accordingly, RA obligations should be adjusted only after the CAISO TPP-approved transmission project reaches the critical milestone of Starting Construction, which is an important measure of project viability. This will ensure that RA requirements are not based on resources that have little chance of becoming operational during the forward timeframe in which the RA obligations are established.

2. RA and CEC Demand Forecasts

Some parties raised concerns regarding the CEC's adopted Demand Forecast (including Updates) and argued that the RA program ought to be modified to correct for the risk that the

CEC may over-forecast demand over the duration of the RA framework. IEP has concerns about this proposal.

The RA program is primarily designed to address grid reliability. To accomplish this, the RA program relies on the CEC-adopted Demand Forecast, including Updates. The RA program integrates the results of the CAISO's TPP into its assessment of need. Together, these two processes represent the official state forecast of supply and demand.

Lowering RA obligations to address individual parties' dissatisfaction with either the CEC-adopted Demand Forecast (including Updates) or the CAISO-adopted TPP could result in significant unintended consequences and prolonged litigation. The RA program must remain linked directly to the official state forecasts of supply and demand. The RA program should not and cannot become a means by which parties dissatisfied with the adopted Demand Forecast or the adopted TPP try to adjust outcomes.

3. Risk of Over-procurement in a Five-year RA Framework

Parties raised concerns regarding the risk of over-procurement if the multi-year RA framework extends to five years with an 80% obligation in the last year, as proposed by IEP. In response, IEP first notes that under its proposal the annual forward obligation declines 5% per year to accommodate the risk of load shift and load reduction.

Second, IEP recommended in Track 1 that the Commission convene a Working Group to identify barriers to LSEs buying and selling RA capacity in the marketplace, including any regulatory rules and orders that serve as barriers to the timely buying and selling of RA capacity by regulated utilities.

Third, in Track 1 IEP proposed the development of an efficient Bulletin Board to facilitate timely and efficient trades of RA capacity. The Track 1 Decision noted that one or more bulletin boards exist for LSEs to buy and sell RA capacity. If tools such as bulletin boards are available but remain unused, the Commission should know why. If efficient and effective bulletin boards are unavailable, the Commission should focus on enabling such tools.

Fourth, IEP anticipates that forecasting of RA capacity needs will improve over time so that forecasts of future RA capacity needs will become increasingly stable and reliably matched to annual need. The Energy Division Staff Proposal addressed the annual variability in local RA capacity forecasting over time in Tables 7-8. These data suggest that forecasting today is significantly more stable (and, hence, more reliable) than forecasting that occurred in the past. RA capacity forecasting will continue to improve over time, particularly as critical inputs such as IRP Plans, RPS Plans, and DER Plans become more developed and sophisticated.

Finally, features like those proposed by IEP are designed to mitigate the risk of over-procurement. These features are designed to facilitate the timely and efficient buying and selling of RA capacity to align RA availability with RA requirements, reducing significantly the risk that an individual LSE will be denied a reasonable means to protect itself against the effects of over-procurement in RA.

4. Risk of Imprecise Forecasting

Some parties have suggested that imprecision in official demand forecasts is cause for reducing forward RA capacity procurement obligations. In response, IEP notes that capacity forecasting is not a precise science. Errors may result in an over-forecast of need as well as an under-forecast of need. For example, recently the CAISO issued a Market Notice (July 26, 2018) indicating that it intended to procure CPM capacity on August 26, 2018, and the CPM designations would commence September 1, 2018. According to the Market Notice, the reason for the CPM procurement was the fact that on July 10, 2018, the CEC indicated at its Integrated Energy Policy Report workshop that the 2018 monthly resource adequacy forecast the CEC provided to both the California and the CAISO was *too low and that it had prepared an alternate* *forecast*. The CEC's alternate forecast for September 2018 was 1,250 MW higher than the forecast used to support the current resource adequacy obligation for the month.

Overall, IEP concludes that the official statewide CEC Demand Forecasts (including Updates) must be the basis on which RA obligations are based. To the extent that parties have grievances or concerns about the official statewide Demand Forecasts, then other forums provide the proper venue for addressing those concerns. On the other hand, the RA program cannot be the forum for rectifying concerns of parties about demand forecasting models and techniques.

VI. PROCESS MATTERS

At the Prehearing Conference on August 1, 2018, parties were directed to address process issues associated with the conduct of this proceeding. Specifically, parties were asked to address how the Commission can best handle outstanding Track 2 issues considering the existing schedule.

Workshops are the best, most efficient vehicle for addressing outstanding issues while keeping on schedule for the Commission to render a Track 2 Decision in December 2018 as currently scheduled. Based on the July 19 Workshop and upon reviewing parties' testimony in this proceeding, IEP concludes that additional workshops or hearings are not required before the Commission renders its decision on the duration and obligation of the multi-year procurement requirement adopted in its Track 2 decision.

On the other hand, the July 19 Workshop and parties' testimony suggest that the Central Buyer concept requires additional discussion in additional workshops.

IEP recommends that additional workshops should be convened in September or October to address (a) ELCC-methodological modifications, particularly the treatment of behind-the-meter solar; (b) local area aggregation/disaggregation, including alignment with between the Commission and the CAISO on RA local area/sub-area designations for purposes of RA.

Currently, hearings are not necessary, because many of the outstanding issues are primarily policy issues. Moreover, hearings could be an impediment to the Commission keeping on schedule to render a Track 2 decision in December 2018. Given the volatility and uncertainty in the marketplace, the Commission needs to send some important market signals in a timely Track 2 decision related to the multi-year RA framework, including duration and amount of the obligation. Some issues might require more time to address, and consideration of these other issues should be continued in Track 3 of the current proceeding.

VII. <u>CONCLUSION</u>

Relying on a voluntary framework to ensure the availability of needed capacity resources over the near term is likely to prove insufficient to ensure the availability of capacity when and where it is needed. Multi-year procurement of needed capacity over the past five years has been highly dependent on the voluntary actions of the IOUs. Non-IOU LSEs (ESPs and CCAs) typically have not voluntarily entered into long-term RA capacity contracts. The current procurement pattern is troubling, because the risk of load departure from IOU bundled service is now at record levels and is expected to increase. Moreover, the Commission and individual LSEs are increasing their reliance on new and emerging technologies for needed capacity at the time when proven, existing capacity is retiring.

The Commission should employ a multi-year framework of relatively long duration (i.e., five years) with relatively high forward obligations (i.e., no less than 80% for the last year of the forward procurement obligation) because of the significant risks and uncertainties that will pervade the California's energy sector over at least the next 2 to 7 years as resources change, load shifts, and the date for achievement of greenhouse emission-reduction goals approaches. A five-year duration at a relatively high annual obligation is necessary to maintain the historical pattern of RA capacity procurement undertaken primarily by the IOUs. RA products ought to be procured in an optimized manner to maximize efficiency and lower overall customer costs. Optimization is needlessly complicated if the products to be procured are subject to different durations or different percentage obligations, regardless of whether the procurement entity is an LSE, a central buyer, or a centralized capacity market.

The Commission need not and should not defer decisions regarding duration and amount of the obligation until the more complex issues are resolved. The Track 2 decision scheduled for late 2018 is the appropriate means for the Commission to set clear signals regarding the amount of capacity to be procured and the duration of the obligation. Policymakers, customers, and suppliers will benefit immensely from clear market signals on these matters.

Respectfully submitted August 8, 2018, at San Francisco, California.

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ATTACHMENT

Docket: Rulemaking 17-09-020

Exhibit No. ____________

Date: July 10, 2018

Witness: Steven K. Kelly

PREPARED TRACK 2 TESTIMONY OF STEVEN K. KELLY

ON BEHALF OF THE INDEPENDENT ENERGY PRODUCERS ASSOCIATION

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PREPARED TRACK 2 TESTIMONY OF STEVEN K. KELLY
ON BEHALF OF THE INDEPENDENT ENERGY PRODUCERS ASSOCIATION

I am Steven K. Kelly. I serve as Policy Director for the Independent Energy Producers Association (IEP), which is a trade association representing the interests of non-utility wholesale electric generators. I have served as Policy Director for IEP since 1994. In this role, I have represented IEP in various proceedings at the Commission related to Resource Adequacy (RA) and procurement, including all of the Commission's multiple long-term procurement plan (LTPP), integrated resource plan (IRP), renewables portfolio standard (RPS), and various RA proceedings. In addition to actively participating in Commission proceedings related to planning and procurement, I have participated in the various Integrated Energy Resource Planning (IEPR) proceedings at the California Energy Commission (CEC) since 1994. I have also provided comments at the Federal Energy Regulatory Commission (FERC) over the years on matters affecting generation development, resource planning, and transmission in California and the West.

I. BACKGROUND/OVERVIEW

The Commission is confronting a period of unprecedented change and evolution in the energy markets.[1] The responsibility of the Commission in setting procurement obligations to maintain resource adequacy remains as critical as ever. The Commission recognized as early as 2006 the potential value of a multi-year, forward RA framework to meet the challenges of the rapidly changing grid.[2] The recent Track 1 Decision (Decision (D.) 18-06-030) (Track 1

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[1] See *California Customer Choice: An Evaluation of Regulatory Framework Options for an Evolving Market Structure* (Draft Green Book), May 2018.
[2] Order Instituting Rulemaking 06-02-013: "In R.05-12-013, we clarified that the Commission intends the

Decision) adopted Local RA requirements for the first two years of the multi-year forward framework. In the first year, the Local RA requirement is 100% of the forward obligation. In the second year, the Local RA requirement is set at 95% of the forward obligation.[3] The multi-year forward RA requirements begin with the 2020 RA program year.[4] The multi-year forward RA requirements apply to all jurisdictional load-serving entities (LSEs).[5]

The Track 1 Decision did not modify the process by which the Commission adopts RA requirements and allocates those requirements to jurisdictional LSEs. In the year prior to the RA compliance year, jurisdictional LSEs file *historical load information* in March; jurisdictional LSEs submit their *year-ahead load forecast* in April; and they receive their year-ahead *RA obligations* no later than July.[6] Furthermore, LSE have an opportunity to *revise their load forecasts* in August prior to receiving their final RA obligations in September. LSEs make their *compliance showing* in October. If found deficient in meeting their RA obligations, LSEs have an opportunity to *cure any deficiency*. Deficiencies in an LSE's showing may be remedied by the California Independent System Operator (CAISO) consistent with its tariff authorities.

While observing that jurisdictional load-serving entities should procure flexible attributes along with local capacity, the Track 1 Decision did not establish obligations for Flexible RA or

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new resource adequacy proceeding to review next generation resource adequacy issues, including local resource adequacy requirements, system resource adequacy requirement compliance issues*, multi-year requirements*, capacity markets, and tradable capacity products." [Emphasis added.]

[3] D.18-06-030, pp. 29-30.

[4] D.18-06-030, p. 28.

[5] D.18-06-030, p. 2.

[6] The CEC first calculates each LSE's specific monthly coincidence factors using historic load dated filed by the LSE. The CEC then reconciles the aggregate of the jurisdictional LSEs' monthly peak load forecast against the CEC's monthly 1-in-2 short-term, weather-normalized, peak-load forecast. Finally, the CEC reconciles the aggregate of the adjusted load forecasts against its own forecast for each utility service territory. "The aggregated LSE forecasts are used by the CEC to create monthly load shares for each TAC area, which are then used to allocate DR, CAM, and RMR RA credits." *The 2016 Resource Adequacy Report*, Energy Division, June 2017, p. 11.

System RA beyond the existing one-year forward obligation.[7] Rather, the Track 1 Decision deferred adoption of a multi-year forward obligation for System RA and Flexible RA pending further consideration in this proceeding.

The Track 1 Decision deferred adoption of a central procurement entity (CPE) for local, system, or flexible RA. The Commission directed parties to propose central buyer structures for multi-year forward procurement of local RA in the Track 2 testimony, while noting that a central buyer structure should address the ability to procure all resource attributes (e.g., flexible RA) and not just local RA capacity to meet requirements.[8] Similarly, the Track 1 Decision deferred consideration of a modified Effective Load Carrying Capacity (ELCC) methodology to Track 2 or Track 3 as needed in this proceeding.[9]

I am concerned that the Commission's adopted two-year forward RA framework is insufficient to ensure overall grid reliability given multiple trends in the marketplace today. I am concerned that even a three-year forward RA framework will prove insufficient to the task of informing the Commission in a timely manner of growing capacity procurement problems. Accordingly, I recommend that the Commission adopt a five-year RA framework as discussed more fully below.

In Section II of this testimony, I highlight key uncertainties in the evolving market structure that support a five-year RA framework. Section III presents IEP's proposal for a five-year RA framework, including its scope and scale and setting the amount of the annual obligations. Section IV addresses additional benefits of a five-year RA framework, such as minimizing out-of-market procurement; the potential impacts on bundled customers, departing load, and disadvantaged communities; and impacts on electric generators. In Section V, I

[7] D.18-06-030, p. 28.
[8] D.18-06-030, p. 32.
[9] D.18-06-030, p. 40.

address the concept of a CPE) and list key principles to follow when considering a CPE. Finally, in Section VI, I propose a "holistic" reform of RA, Reliability-Must-Run (RMR) agreements, and the Capacity Procurement Mechanism (CPM) to better align resource adequacy with competitive markets, thereby reducing the risk of out-of-market backstop procurement.

II. KEY UNCERTAINTIES IN AN EVOLVING MARKET STRUCTURE SUPPORT A FIVE-YEAR RA FRAMEWORK

I generally support the approach adopted in the Track 1 Decision, but I have concerns that the Track 1 Decision will prove insufficient to provide the Commission with the tools it needs to manage grid reliability given the evolving market structure unfolding in California today. A successful multi-year RA framework should inform the Commission and the CAISO of the extent to which the state is resource adequate over the near-term planning horizon where significant market change is most evident; it should send market signals that facilitate orderly retirement of resources no longer needed; and it should maximize the probability that resources needed to maintain grid reliability are procured in a timely manner within the market, rather than being procured out of the market in the context of backstop procurement by the grid operator.

Here, I elaborate on key factors that foster uncertainty in today's evolving market structure and which compel a robust, five-year RA framework to protect against unanticipated and unwanted outcomes that undermine grid reliability.

A. Risk of New CCA Formation

Community Choice Aggregation (CCA) was authorized by legislation in 2001-2002.[10] Thus, the potential for CCA formation is not new. What has been unexpected over the past few years is the pace of CCA formation and, perhaps more important, the increasing risk of future

[10] AB 117 (Migden) enabled cities and counties to aggregate their citizens' electric load and provide direct service to that load.

CCA formation over the next few years. As of 2018, 36 CCAs have been approved.[11] Yet, not all approved CCAs are serving load at this time. Load departure from bundled service to CCA has been estimated to be 20% as of 2017.[12] Up to 85% of the bundled service is at risk of departure to CCAs in the future.[13]

Importantly, evidence suggests that forward contracting of capacity resources diminishes as load migrates from aggregated, bundled service to relatively disaggregated LSE service (e.g., Energy Service Providers (ESPs), CCAs).[14] I conclude that the risk of load migration and disaggregation over the next five years is not a reason for deferring the adoption of a robust multi-year RA framework. Rather, the risk of load migration over the next five years is precisely why the Commission should adopt a five-year RA obligation beginning 2020.

B. Loss of Existing RA Capacity in the Near Term

Evidence suggests that the California electric system will lose approximately 14,000 to 16,000 MW of existing capacity by 2025. First, approximately 9,380 MW of Net Qualifying Capacity (NQC) associated with Once-Through-Cooling (OTC) units are expected to retire by 2022.[15] In addition, approximately 2,240 MW of baseload capacity are expected to shut down by 2024-2025 due to the planned retirement of the Diablo Canyon Nuclear Generating Facility.[16] The California Energy Demand (CED) forecast for the years 2020 through 2027 ranges from

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[11] See *Current Trends in California's Resource Adequacy Program: Energy Division Working Staff Draft Proposal*, February 16, 2018, p. 46.
[12] Draft Green Book, p. 20, Figure 4.
[13] See *Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework*, CPUC Staff White Paper, May 2017, p. 3.
[14] See *Current Trends in California's Resource Adequacy Program*, pp. 49-50. See also, *An Assessment of Capacity Under Contract: An Energy Division Draft Staff Working Paper*, December 22, 2016, pp. 15-20, where data indicate a decline in forward contracting for system and local RA over the past few years.
[15] J*oint Agency Workshop on Risk of Early Econnomic Retirement,* Michele Kito Presentation, April 24, 2017, slide 19.
[16] D.18-01-022.

60,000 to 62,000 MW (low demand case).[17] Accordingly, existing capacity forecast to retire over the next 3-7 years represents approximately 20 percent of forecast demand.

Second, refinements to the ELCC methodology are expected to decrease the available RA capacity deliverable from intermittent renewable resources by 2,500 MW – 4,000 MW depending on the month of the year. For example, the Office of Ratepayer Advocates (ORA) estimates the available RA capacity for all LSEs would decrease by approximately 4,471 MW for the month of August 2018 if the Energy Division's ELCC proposal had been adopted when the annual Local and Flexible RA procurement obligations for the 2016 and 2017 compliance years were established.[18]

Overall, evidence indicates that by 2022 an RA procurement gap of 5,500 MW statewide looms, including a 2,500 MW gap of Local North Capacity and a 3,000 MW gap of Local South Capacity.[19] Importantly, CAISO has presented evidence that "capacity sufficiency issues start to emerge between 4,000 to 6,000 MW of retirement, considering some uncertainties" (assuming no change to OTC policy and the planned closure of Diablo Canyon Nuclear Generating Facility in the 2024-2025 timeframe).[20]

C. Risk of Disorderly Resource Retirement

Existing generation assets require continual maintenance. Older generation assets, particularly, often require significant capital investment to ensure operational availability to the

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[17] California Energy Demand 2018-2030 Revised Forecast, California Energy Commission, Draft Staff Report, January 2018, p. 2.
[18] See *Comments of the Office of Ratepayer Advocates on Final Phase 3 Proposals*, March 10, 2017, p. 14. See also, *Calpine Corporation Final Phase 3 Proposal, Attachment A*, p. 8 (February 24, 2017).
[19] *Joint Agency Workshop on Risk of Early Economic Retirement*, Michele Kito Presentation, April 24, 2017, p. 24. The CPUC Preliminary results reveal the gap between the forecasted RA need and currently procured capacity, which includes utility-owned generation (UOG) and contracted capacity.
[20] *Economic Early Retirement of Gas-Fired Generation – Managing Risk*, Presentation of Neil Millar (CAISO), p. 13 (April 24, 2017). The CAISO's conclusions derive from the CAISO's adopted 2016-2017 Transmission Plan.

CAISO to ensure grid reliability. On the other hand, real-time energy markets create barriers to needed maintenance and capital additions. For example, the CAISO Department of Market Monitoring (DMM) reports that CAISO markets are experiencing an increasing frequency of negative prices in the 15-minute market and the 5-minute market.[21] Importantly, DMM analyses indicate that net revenues earned through the market fell significantly below expected fixed costs (of new generation).[22]

CAISO day-ahead markets and real-time energy markets likely will experience a higher incidence of relatively low and/or negative pricing over the next decade due to the increasing penetration of renewables. Accordingly, the risk of disorderly retirement of generation units due to revenue insufficiency is likely to increase during a period when these resources may be needed to help ensure grid reliability.

D. Growth of BTM Resources Not Visible to Grid Operators

Currently, approximately 6,000 MW of behind-the-meter (BTM) solar resources impact the electric grid, and the amount of BTM solar is projected to double by 2026, representing approximately 12,000 MW.[23] Moreover, individual CCAs are planning for more aggressive and expansive growth of BTM resources, particularly BTM solar. For example, the East Bay Community Energy (EBCE) resource plan includes an innovative NEM program to reduce opt-out activity and provide other benefits. Essentially, the EBCE program builds off the existing Commission-adopted Net Energy Metering (NEM) program administered by Pacific Gas & Electric Company (PG&E) supplemented with a "bonus export credit" to incent higher levels of

[21] 2017 Annual Report on Market Issues & Performance, Department of Market Monitoring (DMM), CAISO, p. 83.
[22] Ibid, p. 59.
[23] *2019 Building Energy Efficiency Standards,* Presentation of Dave Ashuckian, California Energy Commission, CPUC En Banc on Customer Choice, June 22, 2018.

participation than would otherwise occur under the Commission-sanctioned PG&E NEM program.[24]

The Commission plans to address in the 2019-2020 timeframe whether its NEM program should be revised and/or expanded.[25] However, as noted above, the impact of changes or revisions to the Commission's NEM program may be negated to the extent that bundled customers depart to CCAs. Yet, BTM resources have a profound effect on grid operations and reliability. These resources are not particularly "visible" to grid operators on a real-time basis. For example, BTM solar is not dispatchable, operates only during certain hours of the day, and is inherently intermittent and dependent on weather conditions. Importantly, the performance of BTM resources, particularly rooftop solar, is outside the dispatch control of the grid operator for the immediate future.

E. Integrated Resource Planning (IRP) Uncertainty

Public Utilities Code Section 454.52 initiated long-term integrated resource planning at the Commission. Jurisdictional LSEs are required to file an integrated resource plan at the Commission, and the Commission is directed to ensure that jurisdictional LSEs take specific actions to accomplish specified outcomes. Notably, the legislature prescribed critical goals for the Commission which, through the IRP, are passed down to LSEs, including the following:

1. Procuring at least 50 percent renewables by December 31, 2030,[26]

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[24] East Bay Community Energy, *Local Business Plan 2018 (Draft)*, pp. 27-28.
[25] D.16-01-044, pp. 2-4: "In this decision, the Commission . . . [i]dentifies the year 2019, which the Commission has selected as the target for beginning default TOU rates for residential customers, as the appropriate time to review the NEM successor tariff established by this decision, with a view to considering adjustments to the successor tariff that include an export compensation rate for NEM successor tariff customers that takes into account locational and time-differentiated values."
[26] Public Utilities Code Section 454.52(a)(1)(B).

2. Establishing annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings,[27] and
3. Consider means to electrify the transportation sector to reduce dependence on petroleum, meet air quality standards, and reduce greenhouse gas (GHG) emissions.[28]

Individually, these policy objectives pose unique challenges to the operation of the electric grid, particularly because it is difficult to forecast when and where the resources behind these policies will become operational. Collectively, these policies may affect the electric grid in an unknown, synergistic manner, particularly because of their significant scope and scale.

The effort to decarbonize the electric sector (and the transportation sector through electrification) is an immense challenge. The reality is that the state has no experience with the application of new and emerging resources at the pace and scale contemplated by policymakers and planners. The Commission likely will require the passage of time to fully appreciate the impacts of factors such as those discussed above. In the meantime, the Commission must approach the changing market structure with prudent caution.

III. IEP'S PROPOSAL FOR A MULTI-YEAR FORWARD RA FRAMEWORK

The Commission identified grid reliability as one of three core principle guiding energy policies since the 1970s.[29] The Energy Division concluded that forward procurement has decreased approximate 15% since 2014, excluding the effects of ELCC.[30] The incidence of out-

[27] Public Resources Code Section 25310(c)(1).
[28] Public Utilities Code Section 740.12(b).
[29] Draft Green Book, p. 8ff.
[30] *Multi-year Resource Adequacy Requirements/Central Local Capacity Procurement/RA Reform Buyer*, Staff Presentation, RA Workshop, February 22, 2018, Slide 44.

of-market backstop CAISO capacity procurement is increasing,[31] and LSE RA waiver requests appear to be increasing.[32]

The Track 1 Decision focused narrowly on local RA requirements when adopting a multi-year RA framework. The Track 1 Decision adopted a 100% local RA obligation for Year 1 and a 95% local RA obligation for Year 2. The Track 1 Decision deferred consideration of whether a local obligation ought to be set for Years 3, 4, and/or 5 and, if so, at what amount; and it deferred consideration of whether system and flexible RA should be included in the RA framework beyond one year.

I recommend modifications to the multi-year framework adopted in the Track 1 Decision given the many risks and uncertainties that describe today's evolving market structure (as described above). Specifically, as shown in Table 1, I recommend that (a) the system and flexible RA obligations be incorporated into the multi-year RA framework; (b) the forward RA obligations be extended out five years; (c) local RA obligations decline 5% per annum following Year 2, and that flexible and system RA obligations align with local RA obligations for Years 3 through 5; and (d) sub-area local requirements be integrated into the multi-year RA framework if the Commission determines that sub-area requirements are warranted.

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[31] *Current Trends in California's Resource Adequacy Program*, Energy Division Working Draft Staff Proposal, pp. 44-45.

[32] Statements/Questions posed by President Picker, Public Utilities Commission, at the CPUC En Banc on the Green Book, California Customer Choice Project, June 22, 2018.

Table 1:
IEP Proposed Forward RA Procurement Obligation

- *RA Program requirements prior to the Track 1 Decision are represented in YELLOW.*
- *New requirements adopted in the Track 1 Decision are represented in GREEN.*

	One-Year Forward	Two-Years Forward	Three-Years Forward	Four-Years Forward	Five-Years Forward
Local RA Obligation*: Each Month of Compliance Year	100%	95%	90%	85%	80%
Flexible RA Obligation: Each Month of Compliance Year	90%	90%	90%	85%	80%
System RA Obligation*: 5 Peak Summer Months (May-Sept)	90%	90%	90%	85%	80%

*Following the year-ahead showing, the RA program requires that LSEs demonstrate procurement of 100% of their system and 100% of their flexible RA requirements on a month-ahead basis.

Below, I discuss the IEP Proposal in greater detail.

A. 5-year Forward RA Framework

IEP proposes a five-year forward RA framework. Given the many changes in today's rapidly evolving electricity markets that foster uncertainties as to who is doing what, when, and where, I am not convinced that a framework of lesser duration (e.g., three years) will result in transparent, timely procurement of RA resources to ensure grid reliability. Furthermore, I do not believe that a five-year RA framework will be a barrier to CCA formation[33] and/or individual LSEs developing alternative, preferred resources in an orderly manner as they may desire.

As noted above, load migration and disaggregation of load in general is a new phenomenon. In the past, 80% of the statewide load was served by three LSEs, subject to regulatory oversight. Today, energy markets are characterized by 36 approved CCAs (not evenly distributed across the state) and various energy service providers (ESPs). As evidenced

[33] I note that on June 28, the Clean Power Alliance of Southern California, a CCA, issued a Request for Offers for system, local, and flexible RA capacity for 2018-2021.

by increasing out-of-market, backstop procurement and increasing RA waiver requests, the disaggregation of load is creating significant uncertainties as to who will procure the resources needed to ensure grid reliability over the next five years. Coupled with significant retirement of existing resources over the next 3-7 years, I am concerned that a three or four-year forward RA obligation will be insufficient to ensure grid reliability absent significant out-of-market, backstop procurement. On the other hand, a five-year RA obligation will bridge the transition over the next five years. Moreover, a five-year RA obligation will help ensure grid reliability during the mega-transformation to the de-carbonized electric and transportation sectors of 2030.

B. Scope of Framework: Local, System and Flexible RA

The Commission must integrate requirements for system RA and flexible RA procurement in the adopted multi-year framework for implementation in program year 2020 for the reasons outlined below.

i. Local RA

The Track 1 Decision adopted a local RA obligation as a key component of the multi-year RA framework. Separate from issues of duration and annual obligations (i.e., amounts) addressed elsewhere, I do not propose any changes to the local RA requirement. Technical studies conducted by the CAISO to determine local area needs should continue. Yet, the CAISO technical studies should address local RA need over a five-year timeframe, while continuing to be subject to Commission and stakeholder review and comment.

ii. Flexible RA

The CAISO estimates that flexible capacity needs likely will increase to nearly 20,000 MW in 2020.[34] I anticipate the need for flexible capacity will grow beyond 20,000 MW over the

[34] *Flexible Capacity Needs and Availability Assessment Hours Technical Study for 2019* (April 16, 2018), http://www.caiso.com/Documents/Agenda-Presentation-2019DraftFlexibleCapacityNeedsAssesssment.pdf.

next decade due to state resource policies (e.g., Renewables Portfolio Standard) and de-carbonization goals set for 2030. For example, as noted previously, 12,000 MW of BTM solar are expected to be installed over the next decade, nearly doubling the existing penetration of BTM solar due to enhanced pricing options, etc. Resources such as BTM solar uniquely impact supply and demand, but ultimately their presence likely will increase pressures for flexible capacity resources to enable grid operators to align supply and demand in real-time. Accordingly, flexible RA capacity must be fully integrated into the RA framework to ensure stable grid operations in real-time as intermittent resources increasingly impact the electric grid.

iii. System RA

The CEC's adopted demand forecast (10 years forward) predicts modest system-wide load increases over the next decade: "By 2027, sales in the *CED [California Energy Demand] 2017 Revised* mid case are projected to be around 1 percent higher than in the *CEDU 2016* mid case. Annual growth from 2016–2027 for *CED 2017 Revised* averages 1.41 percent, 0.71 percent, and -0.02 percent in the high, mid, and low cases, respectively, compared to 0.56 percent in the *CEDU 2016* mid case."[35]

Existing system capacity resources, however, are at risk of retirement or closure due to several factors, including the retirement of OTC units, closure of Diablo Canyon, retirement of aging existing resources, retirement of stranded resource investment due to insufficient revenues from energy markets needed to sustain operations and needed capital improvements, etc. At the same time, forward contracting of system RA is declining as a percent of aggregate obligations.[36]

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[35] California Energy Demand 2018-2030 Revised Forecast, *Draft Staff Report*, January 2018, p. 14 (emphasis added).
[36] *Current Trends in California's Resource Adequacy Program*, Energy Division Working Draft Staff Proposal, February 16, 2018, p. 42.

The essential purpose of the multi-year RA framework is to ensure that capacity will be available when and where needed in the near term as a bridge to the development of new resources through long-term planning (e.g., LTPP/IRP). The availability of system RA is as critical to ensuring overall grid reliability as is the availability of local and flexible RA.

C. Setting Meaningful Forward Obligations for Local, System, and Flexible RA

The Commission should establish annual forward RA procurement obligations that are meaningful. The Track 1 Decision notes that local RA procurement requirements should be greater than current voluntary local RA forward procurement levels.[37] The Energy Division has concluded that a decrease in forward procurement has occurred since 2014, including a decline of approximately 15 percentage points in system capacity requirements contracted one year before the compliance month (excluding the effects of changes in the ELCC).[38] The Track 1 Decision concluded that LSEs procured only 81% of aggregate 2019 local RA requirements.[39]

Imposing a five-year forward RA obligation is not unreasonable, given that jurisdictional LSEs including CCAs and ESPs are required to forecast their load 10-years forward for purposes of long-term integrated resource planning and for purposes of enabling the CEC to develop its 10-year forward Demand Forecast. Moreover, as is the case today, LSEs including CCAs subject to a five-year RA framework would continue to have the opportunity to revise their load forecast, cure their deficiencies, or sell unneeded RA into the market.

The IEP Proposal provides ample flexibility to address concerns regarding the risk of load migration, CCA opt-out, etc. By setting a forward obligation that declines 5% per annum after Year 2, as shown in Table 1 above, CCAs and ESPs will be required to show in their annual

[37] D.18-06-030, p. 30.
[38] *Current Trends in California's Resource Adequacy Program*, Energy Division Working Draft Staff Proposal, February 16, 2018, p. 42.
[39] D.18-06-030, p. 29.

compliance filing that they have procured sufficient RA resources to match 80% of their allocated RA capacity obligation covering Year 5.[40] All other things being equal, this ratio enables a 20% reduction in load for individual LSEs over a five-year timeframe without any risk of stranded costs. To the extent that the forward procurement obligation results in uneconomic or stranded costs, then LSEs have various means today to sell unneeded RA capacity, including electronic bulletin boards or solicitations.

D. Sub-Area RA

Several parties have suggested that the Commission assess local RA at the local sub-level. Without taking a specific position on sub-area requirements at this time, IEP's Proposal does not preclude integration of local sub-area requirements.

E. Regulatory Process Associated with Determining Compliance

I do not propose to modify the existing process and schedule for establishing annually an LSE's RA forward capacity obligation. I do, however, support reasonable modifications to streamline the process and better align decision-making/actions across the RA, CPM, and RMR programs. I address the alignment across RA, CPM, and RMR programs in greater detail below in Section VI.

Importantly, the procedural and technical changes associated with moving from a one-year forward RA framework to a five-year forward RA framework are not burdensome or unreasonable. Three important changes are required: (a) LSEs will be required to forecast load over a 60-month period rather than over a 12-month period; (b) CAISO/CEC technical studies and forecasts used to determine RA needs (local, flexible, and system) will cover a 60-month

[40] This comparison is used for illustrative purposes. As a practical matter, for any single compliance year, the forward RA obligation allocated to an individual LSE may vary.

forward period rather than a 12-month forward period[41]; and (c) an LSE's annual showings would reflect procurement sufficient to satisfy its obligations in Year 1 through Year 5.

IV. ADDITIONAL BENEFITS OF A 5-YEAR MULTI-YEAR RA FRAMEWORK

A. Minimizing Out-of-Market Procurement

Adopting a five-year RA Framework lessens the risk of out-of-market, backstop procurement through mechanisms such as the Capacity Procurement Mechanism (CPM) or the Reliability Must Run (RMR) contracts under the auspices of the CAISO. As a practical matter, the interplay of the existing RA, CPM and RMR procurement timelines undermines timely procurement and creates incentives for out-of-market procurement.[42] The multiple year forward framework enables the Commission and the CAISO to better assess deficiencies in needed RA resources, highlight those deficiencies to the LSEs, and allow for timely market corrections. For example, if an individual LSE's showing reveals a deficiency in local RA capacity, the Commission can act on this information to fill the looming gap either by requiring additional procurement or, alternatively, authorizing a central procurement entity, if available, to conduct any needed procurement.

B. Impact on Bundled Customers

A five-year RA framework does not impair service to bundled customers nor does it necessarily increase costs to bundled customers. A five-year RA framework increases the probability of in-market procurement (versus out-of-market backstop procurement), thereby ensuring bundled ratepayers of competitive-driven, market-based outcomes in reliability products and services. Importantly, the Commission has adopted or is in the process of adopting

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[41] Technical studies assessing the need for local and/or flexible capacity five years forward have been conducted in the past. See *Flexible Resource Adequacy Criteria and Must Offer Obligation – Phase 2 Supplemental Issue Paper: Expanding the Scope of the Initiative*, CAISO, November 8, 2016, pp. 9-10.
[42] *Review of Reliability Must-Run and Capacity Procurement Mechanism: Issue Paper and Straw Proposal for Phase I Items*, CAISO Presentation at the Stakeholder Meeting, January 30, 2018, pp. 26-27.

several mechanisms to protect bundled customers from being unjustly and unreasonably harmed by forward capacity procurement obligations. Together, these initiatives provide ample protection that the cost of RA products and services procured on behalf of bundled customers will be reasonably apportioned among beneficiaries.

First, the Commission is scheduled to complete in 2018 refinements or alternatives to the existing Power Charge Indifference Adjustment (PCIA) mechanism.[43] The PCIA is a mechanism to ensure that customers departing investor-owned utility (IOU) service remain responsible for costs incurred on their behalf by the IOUs – but only those costs.[44] Adoption of the PCIA refinements in parallel to the adoption of a multi-year framework will help prevent bundled customers from bearing a disproportionate burden of forward RA procurement when existing IOU load departs in the future.

Second, the Commission's Cost Allocation Mechanism (CAM) allocates to all beneficiaries the cost of new generation resources procured to ensure electric reliability.[45] In D.06-07-029, the IOUs as authorized are to procure new generation through long-term power purchase agreements, and the costs and benefits of the centrally procured resources were to be shared by all benefiting customers in the IOU's service territory.

Third, the Commission has instituted a rule that effectively delays CCA service for a year upon proper notification of CCA formation to better align CCA service with RA procurement responsibility.[46] Moreover, the Track 1 Decision determined that participation in the year-ahead

[43] R.17-06-026.
[44] *Scoping Memo and Ruling of Assigned Commissioner,* R.17-06-026, September 25, 2017.
[45] D.06-07-029.
[46] Resolution E-4907.

RA process by all LSEs will be required and should ensure a more equitable allocation of RA requirements.[47]

C. Impact on Load Migration

A five-year forward RA obligation will not impede *future* CCA formation significantly more than a one-, two-, or three-year forward obligation will impede future CCA formation.[48] First, as noted above, the Commission's cost allocation mechanisms (e.g., PCIA and the CAM) will ensure that departing load will be responsible for and receive the benefits of procurement made on their behalf while they were situated as bundled system customers. Second, by setting a forward procurement obligation that declines 5% per year, the IEP Proposal implicitly hedges the risk that any LSE's load, including existing and/or future CCA load, will opt out by 5% in any one year or, alternatively, 10% over three years.[49] In the rare circumstance that a CCA faces an unexpected loss of load greater than 10% over a three-year period, RA capacity remains fungible and of value to other LSEs taking on the obligation of service for the newly absorbed load. Indeed, LSEs today are often buying/selling RA capacity in discrete amounts during the year to better match their procurement with their immediate, near-term need. Moreover, electronic bulletin boards exist to facilitate the buying and selling of RA capacity among LSEs.[50]

Finally, IEP's Proposal will help mitigate the risk of non-viable CCA formation in the future, thereby helping to stabilize energy markets and mitigate concerns associated with the rate of departing load in the future. To the extent that a CCA is not sufficiently capitalized or,

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[47] D.18-06-030, p. 18.

[48] As noted above, on June 28, the Clean Power Alliance of Southern California, a CCA, issued a Request for Offers for system, local, and flexible RA capacity for 2018-2021, a demonstration that viable CCAs are capable of contracting for RA capacity at least four years forward.

[49] Peninsula Clean Energy Authority indicates that the risk of "opt-out" is approximately 2%. See *Comments of Peninsula Clean Energy Authority on Proposed Decision Setting Requirements for Load Serving Entities Filing Integrated Resource Plans,* January 17, 2018, p. 1.

[50] D.18-06-030, p. 45.

alternatively, not sufficiently stabilized with regards to load to engage in relatively short-term RA contracting, then a multi-year framework will shed some light on future CCA viability. As a practical matter, 65 percent of a retail seller's RPS obligation must be met through long-term contracting beginning 2021.[51] Accordingly, all retail sellers, including CCAs, must be prepared and sufficiently capitalized to engage in long-term procurement, and a relatively short-term multi-year RA procurement obligation will not undermine CCA formation.

D. Impact on Disadvantaged Communities

Overall, I do not anticipate that the impact of a five-year forward RA framework will be significantly different than the impact that would occur under a one-, two-, or three-year forward framework. On the other hand, disadvantaged communities stand to benefit from a multi-year framework in several ways. First, sustaining grid reliability at the local level is beneficial to disadvantaged communities because reliable electric service supports the local economy, jobs, tax revenues, etc. Second, a five-year RA framework is not designed nor expected to result in new resources, except perhaps preferred resources such as demand response and storage. In this context, a multi-year capacity-based revenue stream may make the difference in the development of the preferred resources sought by disadvantaged communities.

E. Electric Generation Participation

The Commission is rightfully concerned about the orderly retirement of the natural gas fleet. A disorderly retirement potentially undermines grid reliability, particularly if one or more units in a local area retire in a manner unanticipated or unforeseen by planners or the grid operator. As the Commission implements its 2030 IRP, the Commission should pursue implementation of the IRP with reasonable assurance that the capacity resources necessary to sustain the planned transition to the future, low-carbon grid are available to operate as expected.

[51] Public Utilities Code Section 399.13(b).

The IEP Proposal helps ensure a smooth transition to the low-carbon grid of the future. The five-year forward obligation is aligned with an Operations and Maintenance (O&M) investment cycle typical of natural gas units. O&M can require investments of tens of millions of dollars to maintain and sustain units, particularly in an environment where natural gas units are expected to provide the bulk of the near-term flexible capacity needs of the grid. A five-year procurement obligation provides important market signals to plant operators as to whether sizable O&M investments are reasonable considering market conditions. As a result, a five-year forward RA framework, assuming an 80% obligation in Year 5, creates the conditions for orderly retirement of supply resources and also provides greater transparency of that retirement.

V. CENTRAL PROCUREMENT ENTITY

The Energy Division raised the concept of a central buyer in Track 1, including a central buyer role implemented through the auspices of the utility distribution company (UDC). The Track 1 Decision also addressed the central buyer system, for at least some portion of RA, as a potential viable solution.[52] The Track 1 Decision, however, deferred adopting a framework for a CPE. In doing so, the Track 1 Decision indicated that parties should propose central buyer structures for multi-year forward procurement of local RA in their Track 2 testimony.[53]

I support the concept of a CPE under specific conditions. First, the CPE must be a creditworthy entity sufficient to support long-term contracting. Second, the CPE must be independent from market participants, including the utilities' retail interests, to ensure fair and equitable outcomes. For example, were one or more UDCs to be designated as a CPE, rules protecting against self-dealing and ensuring transparency will need to be considered. Third,

[52] D.18-06-030, p. 32.
[53] Ibid, p. 32.

consideration of a CPE should not become a barrier to implementation of a multi-year framework in program year 2020 as determined in the Track 1 Decision.

VI. OTHER ISSUES: HOLISTIC REFORM OF RA/RMR/CPM

In April 2018, the FERC rejected a CAISO tariff filing associated with various refinements to its CPM, which serves, among other things, as a backstop procurement tool when LSEs are deficient in meeting their RA obligations. In rejecting the CAISO tariff amendments, the FERC pointedly stated: "In this order, for the reasons discussed below, the Commission rejects CAISO's proposed tariff revisions and *encourages CAISO to propose a more comprehensive package of reforms*, consistent with the guidance provided herein." The FERC encouraged the CAISO and stakeholders to make progress to adopt a "holistic, rather than piecemeal, approach" to CPM and RMR reform.[54]

Since the FERC Order was issued, the CAISO has initiated a stakeholder process to consider reform of its CPM and RMR authorities. The CAISO proposes to seek changes in the RA program at the Commission to address increased use of backstop procurement and to change its approach to addressing RMR and CPM issues based on the April 12 FERC Order.[55] Moreover, in recognition of the linkage with the bilateral-based resource adequacy procurement program in California, the Track 1 Decision called for a more holistic approach to local procurement planning.[56]

It is timely to consider a holistic reform to RA, CPM, and RMR in a manner that integrates the various program into a comprehensive approach to ensuring grid reliability, mitigating market power, protecting against risk-of-retirement, etc., while eliminating

[54] Order Rejecting Tariff Revisions, April 12, 2018, Docket No. ER18-641-000 (emphasis added).
[55] *Review of Reliability Must-Run and Capacity Procurement Mechanism*, CAISO Presentation, Stakeholder Working Group Meeting, May 30, 2018.
[56] D.18-06-030, p. 35.

duplication of effort and costs. Specifically, I proposed the following holistic RA/CPM/RMR framework for the Commission's and stakeholders' consideration in Track 2.

Table 2:
Proposal for Holistic Reform of RA, CPM, and RMR

Holistic Proposal	
CPUC Five - year RA Framework	Multi-year Forward RA Requirements adopted by Commission. All CPUC Jurisdictional LSEs subject to the requirement. Applies to System, Local, and Flexible RA. Multi-year RA Requirement presumed to be the sole vehicle to address risk-of-retirement resources.
CAISO CPM Backstop RA Procurement	CAISO "RA Backstop" CPM procurement authorities are limited to the following: • *"RA Backstop*" to cure RA deficiencies. (Maintains status quo) • "*Exceptional Dispatch.*" (Maintain status quo) Proposed Change: CAISO no longer authorized to procure to address Risk-of-Retirement CPM cost compensation mechanism is status quo: (a) competitive pricing; (b) soft-offer price cap, and (c) right of an electric generator to seek cost-of-service in special circumstances. CAISO CPM contracting limited to one-year, i.e., the end of the calendar year after the current RA compliance year.
CAISO RMR	RMR contracting limited to market power mitigation.
Generator Owner Right to Retire	Generators have right to retire upon 6 months *Public Notice*.

I discuss the matrix in greater detail below.

A. CPUC Multi-year forward RA program (5 years)

The 5-year multi-year framework addresses the risk-of-retirement condition now addressed through both the CAISO CPM and RMR programs. A 5-year framework provides

LSEs a forward timeframe within which they can develop new resources, including emerging technologies and preferred resources, to replace existing resources no longer desired, while ensuring that the grid reliably serves load. Importantly, I anticipate that electric generators will choose to participate in the RA procurement space because a multi-year contract is more valuable than a single-year contract that *may* be obtained through either the CPM or RMR programs. Accordingly, this framework should create greater participation in RA markets/solicitations, thereby increase liquidity in those markets and ensure competitive outcomes.

B. CAISO CPM Backstop RA Procurement

I am not proposing any changes to the CAISO's CPM tariff provisions, except to eliminate the CPM authority to procure resources to mitigate the risk-of-retirement of specific resources deemed to be needed in the future for reliability. Under this approach, the CAISO retains the authority to enter into one-year contracts (extending to the end of the calendar year after the current RA compliance year showing) to fill deficiencies in LSE RA procurement that has not been cured by a date certain. CPM costs would be allocated consistent with the CAISO's existing tariff related to CPM cost-allocation.

This provision is expected to require a CAISO tariff change.

C. CAISO RMR Contracting: Limited to Market Power Mitigation

I anticipate that reform of the CPM and RA frameworks will diminish, if not eliminate significantly, the need for RMR contracting. Yet, the risk of the exercise of market power always is present in market structures, particularly energy markets. Therefore, the IEP Proposal retains RMR contracting as a key tool of the CAISO, yet its application is limited solely to the mitigation of market power.

By limiting RMR contracting to market power mitigation and ensuring that procurement to mitigate risk-of-retirement is solely within the RA multi-year framework (bilateral contracting), the issue of "gaming" across programs should be eliminated. As noted above, LSEs will have the opportunity to mitigate market power concerns by procuring new resources to displace resources that exercise market power. If the LSEs choose to not procure resources that can displace existing resources exhibiting market power, the LSEs will pay the full RMR price.

This provision is expected to require a CAISO tariff change.

D. Generator Owner Right to Retire

Uncontracted generators will have the right to retire at any time, if they remain uncontracted, upon Public Notice. Generators will be required to submit a formal Notice of Retirement to the CAISO six months in advance of planned retirement. The CAISO will be required to post the Notice publicly upon acceptance.

This provision is expected to require either a CAISO Business Practice Manual or tariff change.

VII. CONCLUSION

Seven years have passed since the Commission approved D.10-06-018 and stated that a multi-year forward assessment was an indispensable tool that would assist all market participants by providing high-quality official supply and demand information.[57] Current events reinforce the observation that a five-year forward capacity commitment is needed to enhance reliability and provide other benefits. The Energy Division released in late 2016 a Draft Staff Working Paper (Working Paper) assessing forward contracting for local capacity. The Working Paper reported a marked decrease in contracted capacity to meet growing local capacity need. For example, in the Northern California local area, the Working Paper reported a 25% decrease in

[57] D.10-06-018, p. 68.

contracted capacity one year forward (2017) in spite of a 6% increase (682 MW) in the local capacity requirement.[58] Similarly, in the Southern California local area, the amount of contracted local capacity decreased by 36% two years forward and four years forward such that only 52% of the 2020 forecast RA requirement was contracted.[59]

As the Commission explores an integrated policy framework to reduce electric sector GHG emissions by 2030, the key will be to maintain a stable and reliable grid in the near term in the context of fluctuating load among LSEs and growing load to meet increasing demands (e.g., electrification of the transportation sector, population growth, increase economic activity, etc.). Yet, the evidence shows that LSEs are not contracting with resources needed to ensure local reliability and/or ensure adequate availability of flexible capacity to meet forecast short-term needs (i.e., over the next 2-5 years). Moreover, the risk of additional load migration and load disaggregation exacerbates uncertainties and timely action needed to ensure grid reliability.

A five-year RA framework will help identify for the Commission, in a transparent manner, gaps in local or flexible capacity likely to occur over the near-term planning horizon as markets evolve. This information will enable the Commission to act in a timely manner when and where needed to direct local and flexible RA procurement within the market, thereby mitigating the risk of out-of-market backstop procurement. This is a viable path, and it is a path that creates a smooth, reliable transition to the low-carbon grid sought by policymakers.

Specifically, pursuant to the IEP Proposal, I recommend the Commission adopt the following in its Track 2 decision:

- Adopt a five-year forward RA framework that includes all RA products;

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[58] *An Assessment of Capacity Under Contract,* California Public Utilities Commission, Energy Division Draft Staff Working Paper, December 22, 2016, p 18.
[59] Ibid.

- Adopt local, system and flexible RA obligations, with a 5% declining obligation per annum, as proposed in Table 1;
- Integrate sub-area local requirements in the multi-year framework when the Commission adopts such requirements;
- Consider a holistic approach to reforming RA, CPM, and RMR as proposed in Table 2; and
- Consider forward procurement through a central procurement entity that is independent, efficient, and will not pose a barrier to timely implementation of the multi-year RA framework in program year 2020.

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